Summary and Next Steps
Renewable Energy Modeling Series
Modelers' Working Group
February 12, 2003

Next Steps

Details of the next working group meeting will be planned in the coming months, and this meeting will likely include:
-Progress Summary by Wind Modelers (Chris Namovicz, Walter Short, perhaps others)
-Discussion of Ideas about Data Priorities and Strategies
-Presentations on Additional Technologies

Results Summary

Introduction

Tom Kerr, EPA Energy Supply and Industry Branch, introduced the meeting, explained EPA's interest in the Renewable Energy Modeling Series, summarized the first meeting results, highlighted some of the lessons from that meeting, and suggested some goals for this meeting and the next.

EPA is seeking to encourage the use of renewable energy technologies for their environmental benefits, and wants to understand the future opportunities and challenges for the technologies. The Energy Supply and Industry Branch (ESIB) has a Green Power program in which it encourages companies to purchase renewable electricity. The Renewable Energy Modeling Series grew from ESIB's interest in doing more to understand and achieve the environmental benefits of renewable energy. Based on discussions with Skip Laitner (EPA-OAR), DOE, ACRE, and NREL, Tom Kerr developed the Renewable Energy Modeling Series as a forum to convene modelers to assess the status and potential improvements to renewable energy modeling.

The first meeting in the Renewable Energy Modeling Series convened policy makers to identify their renewable energy analysis needs. Some of the lessons to date were:
- It is important to include industry, government, NGOs
- Providing a forum for open discussion on modeling issues is valuable
- There are so many potential topics for discussion that it is very important to focus on top priorities.

This meeting will focus both big picture issues of externalities and environmental benefits, as well as details on Wind Energy Modeling.

Session 1. Modeling Energy Market Effects of Renewable Energy

Skip Laitner Senior Economist for Technology Policy, Office of Atmospheric Programs, EPA, and energy modeling expert, presented an overview on macroeconomic impacts of EERE in technology policy scenarios. Skip has reviewed the results to understand why renewable energy is not expected to penetrate more, and has concluded that macroeconomic modeling is usually not set up to represent the benefits of renewable energy. For example, environmental externalities are often assumed to be of no value.

Also, models generally use the assumption that GDP is inversely proportional to energy price. Skip developed an alternative modeling framework to demonstrate how investment in energy efficiency and renewable energy could provide net economic benefit. Based on this research, he recommended changing GDP algorithms in other models so that they could better represent potential benefits of addressing environmental externalities and providing more flexibility in meeting environmental and energy goals.

Questions and comments from the audience addressed the suitability of GDP as a measure of economic benefits, trade-offs among investments, and the use of IPM linked to REMI to provide greater modeling detail of economic performance.

Session 2. Modeling Wind Energy

Jim Caldwell presented an *Overview of Issues in Modeling Wind Energy,* focusing on short term operational issues for wind energy, and how their representation in long term energy models may be improved. The challenge of modeling wind energy arises because the standard deterministic generation models don't work for wind because of wind's spatial and temporal variance and the independence of each wind turbine. Modeling wind like a negative load is better, but must be done right. Added complications include the site-specific nature of wind integration issues, continued changes to wind technologies and costs, and limitations in modeling of transmission capacity. With greater penetration of wind, grid operators are starting to need additional control ability, rather than simply on-off control. Mr. Caldwell noted that, as a rule of thumb, 10% penetration of wind in generation could be accommodated throughout the U.S. without special measures. Approximately 80-90% of the grid could accommodate 15-20% wind. Up to 40% wind could be accomplished with greater controls, and above that additional capital investment would be needed.

Jim addressed wind operational issues on four different time scales: below 1 minute (system stability/power quality), below 10 minutes (automatic generation control), below 3 hours (unit dispatch/load following), and 3 hours to 3 days (unit commitment and scheduling). He concluded that improvements in operational practices and models are being done now, and this is a timely development. In turn, these improvements in operational models will inform long-term scenario models such as those under consideration in this workshop.

Additional notes on Jim's presentation are included in Appendix 1.

Walter Short facilitated the **Panel Discussion** on questions about wind energy modeling. This panel considered each of the following questions in turn:

1. How does the model determine the market penetration of wind?
2. How does the model determine the amount of wind resource available?
3. How does the model determine the cost of wind power generation?
4. How does the model treat the intermittency of wind?
5. How does the model treat transmission of wind?

Regarding question 1 on market penetration, the models use different approaches to represent the effects of green pricing on market penetration. NEMS does not now model green pricing, but could use its RPS modeling approach to do so. AMIGA has been used to show effects of green pricing. Mini-CAM, in contrast to the others, looks at a much longer-term time frame in which capital stock turnover creates greater opportunities for penetration of cost-effective, low carbon electricity and hydrogen generation technologies.

On question 2, wind resource, NEMS, MARKAL, and AMIGA all base their wind resource representation on the PNL wind atlas database, while Mini-CAM does not represent wind resource in detail.

Question 3 on cost of wind power showed a range of assumptions on capital cost, capacity factors, variable costs, and operations and maintenance costs for wind.

On question 4, transmission, the modelers used a variety of approaches to represent cost and availability of transmission capacity. NEMS uses the same region-specific transmission cost charges for all generation types, including wind and adds wind-specific costs based on distance from existing transmission and extensive resource utilization. MARKAL would be able to include specific transmission charges in state-level versions of the model, but does not represent transmission in the national model. AMIGA and Mini-CAM do not represent transmission at this time.

Regarding question 5, intermittency, the models varied substantially in their approach. NEMS uses reductions in the capacity credit to represent intermittency: the current approach also includes a 20% limit on intermittent (wind + solar) capacity in each region because of surplus production. MARKAL represents intermittency by using one factor to show the contribution to capacity and another to show the contribution to energy. AMIGA uses a cap of 22% wind contribution to generation by 2050. Mini-CAM will not directly represent intermittency, but rather would use results of other models where this is done.

Questions and comments from the audience addressed the expectation of decline in fixed operations and maintenance costs, which audience members thought would make a substantial difference for wind penetration. For example, modelers may wish to represent operations and maintenance as a function of regional penetration rate, because historical data supports the proposition that O&M costs a lot when there is a single wind farm operating in isolation. Discussion also focussed on how low current bid prices are, below 3 or perhaps even 2 cents per kWh. Other comments addressed the fact that only long term models are represented here, and that short term issues are represented in long term models in reduced form, and that this is not done well. Ideas on what to do better included:
-Technology learning functions
-Representation of resource
-Effect of technology investment on economy
-Ancillary services cost, including transmission and integration costs for large amounts of wind

Modelers highlighted their highest priority as follows:

NEMS: Incorporate new wind resource data, use new intermittency algorithm, address the over-production issue, address long term elasticity.
MARKAL: Incorporate transmission by developing a disaggregated model, address intermittency/dispatching concerns, obtain data and develop methodology for distributed generation

AMIGA: Integrate easy wind fixes as possible, but wind is lower priority than other improvements (e.g. other GHGs)
Mini-CAM: Incorporate new resource data and cost data, address transmission. Will not represent intermittency directly in model.

Walter Short presented on the *Wind Deployment System Model.* One intent in the development of this model is to provide insights for the development of "reduced forms" to include in models such as those discussed on the panel. Therefore, this model is limited to the electricity sector, and seeks to explore transmission and intermittency issues in detail. The model includes 358 supply and demand regions, selected to separate loads from wind resources so that transmission can be modeled. The large number of regions also allows comparison among different transmission cost distribution approaches. Regional disaggregation also allows detailed assessment of intermittency issues because the model can estimate the impacts of dispersing wind farms to reduce the correlation in their output and thus reduce their intermittency impacts.

Questions and comments from the audience on wind modeling addressed the temporal variability in wind capacity factors, with 4 seasons and 4 times of day thought to represent most of this variability. Overall questions were raised such as the value of class 4 wind, the tradeoff between operating reserve and backup requirements, expectations about future transmission needs, market acceptance, and relative importance of modeling of macroeconomic issues vs. technology issues.

Summary Discussion and Action Items

Skip Laitner facilitated a summary discussion that addressed data issues, modeling issues, and macroeconomic issues, as well as potential future directions.

Some of the data issues for wind included actual costs, improved resource data such as including temporal variation in wind, transmission bottlenecks, and interconnection data.

Priority modeling issues seemed to be transmission, externalities, user preferences (green markets), and macroeconomic issues.

Potential future directions for the next meeting include presentation of updates on wind energy modeling and considerations of additional technologies. Regarding wind modeling updates, Chris Namovicz could update the group on progress in changing NEMS, and Walter Short could present WinDS modeling results. Biomass (including electricity, ethanol, and biodiesel) and PV were the leading suggestions for additional technologies. It was also suggested that it is useful to have perspectives from industry representatives who can provide real-world perspectives on cost and performance and implementation issues.

Appendix 1: Notes on "Overview of Issues in Wind Energy Modeling" by Jim Caldwell

These notes are organized to correspond to slides from the presentation. The first slides are covered in the summary paragraph, above.

SLIDE 4: Modeling Power Quality/Grid Stability

The available computer programs to assist in managing grid stability are not capable of modeling the various types of asynchronous wind generators in use today, or collections of these machines at a common point of interconnection, such as wind "farms." Instead, wind generation is usually modeled as a simple squirrel cage induction generator equal to the wind farm nameplate capacity, which tends to exaggerate stability issues.

This modeling practice is especially problematic on "weak" grids which are common in the mid continent area of the country. A weak grid means one that is primarily "radial" with long distances between interconnections – thus there are few alternate paths for power flows.

The software developments that are under way will represent wind better in the industry standard computer programs PSS/E and PSLF, especially including different types of wind turbines, their effects on power quality issues, and including effects in aggregate.

Grid operators have not traditionally thought about turbines as an essential energy source. Their approach to power quality has been to take wind turbines off line when there is a problem. This means that turbine controls have been designed to "trip" at the first sign of instability. However, now that larger amounts of wind are being used, grid operators want turbines that "ride through" disturbances. Controls for turbines and wind farms need to be redesigned accordingly before high penetration is reached.

Several different groups are working on these control issues. Although Denmark and Germany have high penetrations of wind, their grids are strong and so have not required the same level of control at the generator to date. IEC and IEEE are actively working on control standards. ERCOT has taken the lead in the United States because transfers from west Texas to load centers in the east are currently stability-limited. These controls will also improve power output by 1 to 3 percent.

In response to a question about how much wind generation could be accommodated on the grids with this type of control, Jim noted that, where there are weak grids (about half of the U.S. grid), it can easily take up to 15 to 20 percent, or in extraordinarily weak places, maybe 10 percent. After that level of penetration, relatively small investments in transmission upgrades are needed. For higher penetration of perhaps 40 percent annual average energy, significant capital investment may be required. This does not include consideration of storage, which would only be secondary to other improvements.

New controls will result in a slightly more expensive turbine, but cheaper interconnection and greater efficiency will more than make up for the expense.

SLIDE 5: Modeling Regulation/Spin Requirements

(Bullet #2) The requirement to balance the whole system means that wind should not be considered alone, but rather that variations in the wind, other generators, and the load should be considered together.

(Bullet #4) This means that there is little cost impact until wind penetration is the largest single generator, if potential outage of all the wind is correlated (e.g., if it is all on the same transmission line).

SLIDE 6: Modeling Unit Dispatch/Load Following Impacts

(Bullet #3) The energy and capacity related operating reserve impacts of wind generation generally average about 3% of nameplate capacity with occasional spikes to as high as ~11% of nameplate wind capacity.

As the annual average energy from wind approaches 10%, capital expenditures are needed on weak grids to handle the variation in wind and its impacts on transmission. Although this is traditionally thought of as a generation expense, it may be cheaper and more efficient to invest in transmission rather than generation reserves.

In response to a question about how to determine a $/MWh cost for these equipment requirements, Jim estimated that perhaps $5/MWh allows penetration to go from 10 percent up to 20 percent. Higher penetration rates, above 30% annual average wind penetration for a NERC region, are a distant future scenario, and may require storage.

Once FERC completes a new standard market design tariff, the transmission system will be used more efficiently and utilities will stop balancing the load over all 180 control areas. The new tariff would reduce costs compared to the current pro forma tariff which can impose non-cost based penalties as high as $25/MWh. This new approach to using the transmission system, which will include locational marginal pricing and robust spot markets, should free large amounts of transmission capacity, raising the capacity to transfer between control areas, and raise the effective capacity on the grid. Thus greater integration across regions allows less generation reserves to be used. For wind, this will also improve its ability to compete with coal for dispatch, and the price of marginal capacity will fall.

SLIDE 7: Modeling Unit Commitment/Scheduling Impacts

(Bullet #2) Industry scheduling protocols require more specificity than wind prediction can achieve.

(Bullet #3) Current high penalties for not delivering as scheduled were designed to prevent “gaming”—that is scheduling to deliver during expected high price periods but actually delivering during low price periods.   Protocols can be designed so that wind will not be unduly penalized. For example, regulators could let wind have a wider margin of error as in Texas, or let wind providers schedule their net generation over a 1-month time frame if they commit to schedules derived from statistically neutral forecasts as in California.

(Bullet #4) Regarding the unit commitment timeframe, conventional modeling works equally poorly for wind and everything else.

Comments from the audience led to a discussion of the different costs of implementing wind in different grids. Cost depends on grid strength and options available to balance the system. For example, in Denmark, 1 mil/kWh of cost covers the system issues associated with 24 percent wind penetration. These costs are kept low because the Danes implement forecasting, have access to Norwegian hydro, and have a strong grid. Within the U.S., Bonneville could easily accommodate 30 percent wind penetration because of its hydro, whereas Oklahoma would probably have high costs after 10 percent because it lacks hydro and has a generally weak grid.

SLIDE 8: Modeling Capacity Value

How do you count wind against capacity planning requirements? New York, California, and Texas do this well; The Pennsylvania-New Jersey-Maryland power control area does a bad job but is studying the issue. Capacity value (the percentage of nameplate capacity that can be used to meet capacity planning requirements) can be higher than capacity factor (percentage of nameplate capacity that is actually generated over a specified time period) if there is a better load match, however, in most places, capacity value is less than capacity factor.

Most areas tend to use a 20 to 25 percent capacity value for planning purposes.

Michael Milligan of NREL is a good contact on this topic.

SLIDE 9: Transmission Capacity/Interconnection Issues

One major issue is that even congested paths have transmission "capacity" for most of year, but wind developers can't get a contract because the transmission is not <u>always</u> available. This is being fixed by regulatory changes that will allow better, more flexible use of the existing grid.

Once regulatory reform achieves optimal use of the existing grid, there is still a need to look at building regional transfer capability to allow inter-regional transfer of wind energy. For example, one estimate shows that 120 to 140 GW of wind could be made available with $20 billion in regional transfer capability.

The new FERC rules for optimal use of the existing transmission system will be implemented over the next 2 years to 2 decades, depending on regional politics and constraints. About $1 billion in investment is needed to make the change and political acceptance is not universal. Note that accommodation of wind energy is NOT the stated reason for the change.

An example of transmission construction issues being addressed at a regional level occurred in Minnesota, where no transmission had been built since 1975. The cheapest wind is in the southwestern part of the state, but the 300 MW of capacity there had fully loaded the existing transmission system. Developers wanted to build 825 MW in the area, which required $160 million in lines however each individual wind project could not support the upgrades which are much cheaper if constructed simultaneously. The

Minnesota Public Utilities Commission found a need for the transmission upgrade to facilitate the development of all of the wind energy projects, and therefore allowed rate basing the transmission upgrade costs.

Because these transmission system issues are regional, it can be hard to achieve political cooperation.

SLIDE 10: Data Requirements for Wind Modeling

(Bullet #1) As the wind mapping is done state by state, there is a need to look at the edges of the states to be sure that the transitions are right.

(Bullet #2) “EEI format” output matrices need to be on an hourly basis, the way load statistics are kept. Anemometer data is often proprietary project data. Time stamped data, often absent, would be useful to determine capacity value and model integration costs.

Comments from the audience raised questions about Canadian wind and off-shore wind. Canada has substantial wind resources and a relatively small population compared to the U.S., and so could export wind power. Offshore wind requires strong wind and shallow water to be economic, because it costs at least 20 to 30 percent more. The Great Lakes have fairly good resources, but there’s little reason to go off-shore because on-shore sites are available. Long Island and Cape Cod may be the only economically important off-shore resources.

Discussion also focused on land uses that might compete with or exclude wind development. Planning maps have been completed to identify the developable acres. Generally, where wind is commercially significant, there isn’t a competing use although there clearly are exceptions to this “rule.”

(Bullet #3) Even where wind output data are available, time stamped utility control area imbalance data are generally not available. These data are needed so that system planners can determine at what percentage penetration of wind more control would be needed.

SLIDE 11: Cost/Performance Modeling of Wind Turbines

(Bullet #1) Achieving low costs of installed wind depends on low land costs and on economies of scale from many deals in an area that shares “infrastructure” for construction and operations.